AL.1.15 c2

CANADIANA

NOV - 2 1990

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 90-5

TO: All Oil and Gas Operators

23 October 1990

APPLICATIONS FOR APPROVAL OF GAS PROCESSING SCHEMES — POLICY ON PLANT PROLIFERATION

This informational letter is to clarify the Board's current position on the development of new gas plants and the need to avoid plant proliferation. The primary objective of this new focus is to provide some assurance that applicants have investigated the feasibility of using existing plants when examining potential gas processing options. No new legislation or changes to existing regulations are contemplated.

The growth in resource development over the past decade has generated increased public awareness of the potential for industrial impact throughout the province. From many submissions made to the Board it is clear that the public is reacting in an adverse way to new industrial facilities. New facilities commonly create land-use conflicts and prompt concern about local environmental and social impacts. Applicants for new facilities frequently argue that despite these impacts they are compelled to build such facilities because of inordinate custom processing fees charged by existing plants in the area.

To ensure these concerns are addressed, the Board intends to continue to promote an approval process that enhances conflict resolution at the local level from the outset of the planning process, and to encourage increased use of existing facilities where local concerns about industrialized impact cannot be overcome. In general, the Board believes developers of new gas processing plants should recognize and strike a balance between various public interest issues, and decisions should not be tailored exclusively to suit individual resource ownership in the area or dominated by a desire, on the part of individual companies, to control processing plants. As outlined in the attached guidelines, the Board expects operators will vigorously explore all reasonable options to use existing plants in the area and expects these efforts to be documented in support of an application to expand or add new facilities. The Board appreciates that there can be many factors which make a new plant preferable to using an existing one and will not preclude its development if the circumstances warrant a new facility. Each application will continue to be evaluated on its own merits.

The Board is convinced that pro-active negotiation within the industry and recognition of public interest issues in the development process will lead to more optimum use of facilities. It is also prepared to assist industry and the public in resolving problems if that is of some benefit.

While the objective of this policy applies to all gas plants, the Board observes that the problem of plant proliferation largely relates to new facilities with capacities below 500 x 10^3 m^3/d.

Questions respecting this matter can be directed to Mr. Jim Dilay of the Board's Gas Department at 297-8506 or Mr. Bill Schnitzler at 297-7322.

E. J. Mink
Board Member

Attachment

ATTACHMENT TO IL 90-5

GAS PROCESSING PLANT APPLICATIONS: INFORMATION REQUIREMENTS ON FACTORS RESPECTING THE FEASIBILITY OF USING EXISTING OR EXPANDED PLANTS

The following presents the Board's views on several factors respecting the feasibility of using an existing gas processing plant as opposed to building a new one.

PUBLIC CONSULTATION

The Board believes that involvement by the public directly affected by new facilities should be an integral component of facilities planning. Guidelines on how that may be accommodated are outlined in ERCB Informational Letter IL 89-4[1].

AVAILABILITY OF EXISTING GAS PLANT CAPACITY

Section 15.050(3)(w) of the Oil and Gas Conservation Regulations specifies that an application for approval of a gas processing scheme must include a general description of the feasibility of using a single larger plant in the area rather than two or more smaller plants or the feasibility of expanding a nearby existing gas processing plant to handle the additional gas.

If existing plants do not or will not have sufficient capacity to process the additional gas, the Board will require historical statistics and production forecasts to demonstrate the lack of capacity. Applicants for new plants will be asked to address the technical and economic feasibility of expanding an existing plant to provide the required additional capacity. Where adequate capacity exists or could be readily obtained through expansion of an existing plant, applicants will be asked to document the efforts that have been made to secure processing arrangements, confirm in writing the terms of those negotiations, and provide details why the terms were found to be unsuitable. If it is not feasible or desirable to expand an existing plant, applicants for new plants must provide a detailed comparison of the technical, environmental, economic, and other factors between the two options.

LACK OF UP-TO-DATE TECHNOLOGY FOR SULPHUR AND LIQUIDS RECOVERY

Older plants may not be capable of achieving the degree of processing efficiency available from newer plants having more up-to-date technology. This is particularly true for sulphur recovery, which is a very significant environmental issue, and liquids recovery, which can have a significant impact on

---

1 Energy Resources Conservation Board and Alberta Environment. Public Involvement in the Development of Energy Resources.

project economics. The requirements for sulphur recovery are set out in Informational Letter IL 88-13[2], including those cases where gas is being added to an existing plant or an expanding plant.

Applicants may resist using existing plants if the addition of gas to the existing plant would necessitate the addition of sulphur recovery or would require increased sulphur recovery to meet the province's guidelines. The Board expects the new guidelines to be met whether or not a new or existing plant is under consideration and recognizes that in most cases the addition or upgrading of sulphur recovery will be required regardless of whether or not existing or new facilities are developed. It also recognizes that in some cases the cost of adding or upgrading sulphur recovery at an existing plant may be significantly greater than the cost to achieve the required sulphur recovery in a new plant, and therefore make upgrading the existing plant uneconomic.

With respect to liquids recovery, the Board would need to be convinced that the increase in liquids recovery, having regard for the capability of the straddle plants on the NOVA system, is sufficiently greater than the status quo to warrant the requested approval for a new plant.

TRANSPORTATION ON THE NOVA SYSTEM

In some cases an existing plant cannot be used as there is insufficient firm NOVA transportation available on the existing lateral; provision of firm capacity cannot be made in time to prevent substantial drainage or to meet the sales contract conditions. In general, the Board would expect the planning process and regulatory process to be sufficiently advanced to avoid transportation conflicts. The Board is well aware, however, of the difficulties which currently exist in acquiring capacity on the NOVA system. To circumvent the problem, NOVA has offered to give special consideration to resolve the matter where, in the view of the Board, plant proliferation or resource conservation such as the recovery of solution gas is a particular public interest issue. The Board believes that NOVA capacity is a short-term constraint that must be measured against the long-term consequences of adding a new facility. Applicants for new gas plants claiming a transportation constraint will be requested to document the results of their discussions with NOVA as part of an application. This should include evidence showing that NOVA capacity is not available and under what circumstances it would be.

DRAINAGE AND INTRA-POOL EQUITY

With respect to drainage concerns, the Oil and Gas Conservation Act includes provision for the Board to designate common purchasers, common carriers, and/or common processors where it is convinced that such orders are necessary or to allow each owner in a pool an opportunity to produce his equitable share. There are also rateable take provisions in the legislation which are intended to provide for equitable rates of production between producers. The Board expects these options to be considered in an effort to resolve equity problems at an existing plant prior to an application being made for a new plant. ERCB regulations permit the Board to make retroactive adjustments to the date of a legitimate rateable take application, substantiated with evidence of unequitable drainage.

---

2 Energy Resources Conservation Board and Alberta Environment, August 1988. Sulphur Recovery Guidelines – Gas Processing Operations. Informational Letter IL 88-13. Calgary, Alberta.

CAPACITY REQUIREMENTS FOR PROJECTED DRILLING SUCCESSES

The Board recognizes that it is prudent that consideration be given to the prospects for future processing needs in the area. Indeed, the provision of some spare capacity in new plants, while it may give the appearance of plant under-utilization for the initial period, might avoid a proliferation problem later. At the same time it must be recognized that spare processing capacity will emerge at existing plants as proven reserves are depleted. In new plant applications where a plant already exists, the Board expects applicants to provide sufficient evidence to show new resource development and markets will likely exceed the available capacity in the area in the long term.

CUSTOM PROCESSING FEES

It is well understood that access to existing plants and a fair fee for custom processing are vital elements to avoid plant proliferation. The Board notes that, in response to a request from the Honourable R. Orman, Minister of Energy, a joint industry task force produced a report, "Gas Processing Fee Guidelines – Jumping Pound 1990 (JP-90)". These guidelines are designed to promote negotiation of fees and contemplate an arbitration process that could be used to more expediently settle disputes. While the Board has no jurisdiction in the matter of processing fees, it notes that the Public Utilities Board (PUB) under the Gas Utilities Act has jurisdiction to deal with complaints respecting processing fees. Therefore, the Board takes the position that, if an unacceptable processing fee is demanded by the existing plant operator, this may not necessarily preclude the use of the plant as there is recourse available through the PUB to resolve the dispute.

REFERENCES

Recent gas plant applications and Board positions related to plant proliferation that may be helpful to the reader are:

	Company	Application	Decision Report
1.	Hewitt Oil (Alberta) Ltd.	850583	D 86-3
2.	Chevron Canada Resources Limited	871060	D 88-8
3.	Chevron Canada Resources Limited	871435	D 88-9
4.	Norcen Energy Resources Limited	861041	D 88-22
5.	Universal Explorations Ltd.	870772	D 88-23
6.	Unocal Canada Management Limited	880830	D 89-7
7.	Altex Resources Ltd.	891425	D 90-6
8.	Shell Canada Limited Husky Oil Operations Ltd.	890971 (Proceeding)	D 90-8

9. "The ERCB Position on Gas Plant Proliferation": presented by F. J. Mink to Info-Tech Gas Plant Optimization Conference, 7 June 1989, Calgary, Alberta.

AL.1.151 c.2

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 90-6

CANADIANA
JUN - 5 1990

TO: ALL OIL AND GAS OPERATORS

23 May 1990

MEASUREMENT GUIDELINES
TRUCKED OIL PRODUCTION

The Energy Resources Conservation Board is responsible for ensuring accurate measurement and accounting procedures at all oil and gas production facilities. Measurement and accounting accuracy is necessary for appropriate allocation of oil and gas production to individual wells to provide for meaningful technical reservoir and production assessments, as well as to facilitate both royalty and working interest equity allocations.

The Board has reviewed measurement and accounting practices at facilities receiving trucked oil production. It has concluded that receipt of trucked production, in the absence of suitable measurement and accounting procedures, can be a significant source of measurement and accounting error. This applies to proration batteries receiving both trucked and flowlined production, as well as to facilities receiving only trucked production. As a significant portion of the province's crude oil is transported by truck, the Board believes this matter warrants some direction.

Background

Receipt of trucked production at a proration battery and the method of volume and basic sediment and water (BS&W) determinations introduce an error system additional to that already inherent in the proration battery. Errors in both the inlet volume and BS&W determination of the trucked volumes are generally absorbed by the flowlined production, as the trucked volumes are considered as measured such that these errors are not prorated back to the trucked wells.

Although one apparent solution would be to prorate any differences between estimated and actual battery production back equally to both

flowlined and trucked wells, the Board does not believe that this is a reasonable approach. The concept of proration requires that all wells contributing to the proration battery be subject to an equivalent error or uncertainty regime. In the case of trucked production, each load or unit volume from the well or battery is subjected to measurement such that the total production is in fact a measured volume. This is significantly different from the flowlined wells which are subjected to periodic test measurements with the total well production estimated from these tests. Measurement devices and procedures are also typically distinctly different between the trucked and flowlined systems. Given the difference between error regimes, the Board believes a more appropriate solution is to minimize the error or uncertainty in trucked production measurement.

The Board will continue to require operators of facilities receiving only trucked production, such as central treating stations, to prorate errors back equally to all contributing wells despite the fact that each load is measured. This is consistent with the aforementioned philosophy, as all wells included in the proration are subject to the same uncertainty regime. Similarly, trucked production at proration batteries may be subject to proration when separate treating facilities are available to determine the trucked volume available for sale.

As a result of its review of existing facilities, the Board expects that all facilities receiving trucked production either have in place or take steps to implement measurement systems sufficient to provide for accurate determination of both the volumes and BS&W cuts of the production being trucked. In accordance with the Board's production accuracy standards as listed in Schedule 9 of the Oil and Gas Conservation Regulations, it is intended that total battery oil trucked from single well batteries be determined to within 0.5 per cent error. As trucked volumes are considered measured and accounted for as a delivery to the receiving battery, the accuracy guideline must be consistent with custody transfer measurement. Unlike typical custody transfer measurement, however, the Board recognizes that the untreated and potentially high water content characteristics of the trucked volumes from single well batteries makes the 0.5 per cent accuracy guideline extremely difficult to achieve. Such accuracy can be achieved on a volume basis but is compounded by uncertainties in BS&W determination. Accordingly, the Board recognizes the accuracy guideline in this case as a target rather than a requirement.

To achieve the desired accuracy would require either a separate treating process train for the trucked volume or refusal of proration batteries to accept trucked production, thereby requiring all trucked volumes to be processed through central treating stations. The Board believes the former may be warranted where trucked volumes are significant in comparison to flowlined volumes. The latter, however, is recognized as impractical from an operational perspective. Receipt of trucked production at proration batteries without separate treating facilities therefore represents a compromise between measurement accuracy and operational practicality.

Inlet measurement systems for receiving trucked production are therefore expected to have both a means of determining inlet truck volumes and appropriate procedures for BS&W determination to assist in approaching the target accuracy. It is not the Board's intent at this time to stipulate specific equipment designs, configurations, or procedures. The Board prefers to leave the operators flexibility in implementing measurement systems. In recognition of the wide variety of operational scenarios to which this informational letter may apply, the Board believes it appropriate to present the following recommended guidelines for volume and BS&W determination. Much of the following guidelines has been derived from work performed by a committee formed to study measurement accuracies at pipeline terminals, tailored to fit the situation of battery level measurement.

Inlet Volume Measurement

A system must be in place to provide for accurate measurement of inlet volumes of trucked oil production. Truck tickets are not considered accurate for the purpose of well or battery level measurement. The Board believes an accuracy of 0.5 per cent can be achieved with respect to gross volume alone through a system consisting of either inlet tankage, inlet meter, or weigh scale.

i) Tankage

Inlet tankage used for the purpose of truck volume measurement must be of sufficiently small diameter in relation to load volume to facilitate gauging accuracy to within the Board's accuracy guideline. Having regard for uncertainties in gauge tape accuracy and gauge tape reading, the maximum acceptable tank diameter (metres) can be approximated as 1.04 times the square root of the delivery volume (cubic metres). Tanks must be gauged prior to and after each well delivery, and gauging should be in accordance with the applicable sections of API Standard 2545. Calculation of volumes as obtained from gauging must be based on appropriate strapping tables and should include temperature compensation factors to 15°C. In cases where density differences between adjacent loads exceed 40 kg/m^3, consideration should be given to use of dedicated tankage or the appropriate density blending tables as per API Bulletin 2509C.

The use of differential pressure transmitters is an acceptable option to gauging if appropriate procedures are followed to determine a representative load density as per API Manual of Petroleum Measurement Standards, Chapter 9.1. Gauge boards are not considered accurate enough for the purpose of this measurement.

ii) Meters

Metering devices for the purpose of measuring inlet truck volumes should be installed in conjunction with a strainer and air eliminator. The meter must be operated within the meter design flow range either through installation of a back pressure control system or an alternative means of regulation of the truck unloading rate. Meter selection must be appropriate for the intended range of service having regard for the range of fluid characteristics (ie. density, viscosity, temperature) to be encountered. Meters must be calibrated monthly and temperature compensation should be included with the meter.

iii) Weigh Scales

Weigh scales for the purpose of inlet measurement must be calibrated monthly in accordance with Canada Weights and Measures Standards. Systems employing weigh scales must also provide for density determination. Determination of density for oil and water should be in accordance with API Manual of Petroleum Measurement Standards, Chapter 9.1.

BS&W Determination

The largest component of uncertainty in trucked production measurement typically pertains to the determination of BS&W. Procedures for determination of the BS&W cut of individual truckloads must provide for obtaining a representative sample of the entire truckload, and reliable phase separation of the sample obtained. Difficulties can be encountered when dealing with emulsions subject to significant free-water breakout prior to treating, as free water may separate in the truck and unload for a short period prior to unloading emulsion. Sampling procedures therefore become vitally important with respect to ensuring that the entire load is represented. Automatic sampling procedures are preferred; however, manual or tank sampling systems may also be appropriate.

i) Automatic Sampling

Automatic sampling is typically conducted through the use of either proportional samplers or product analysers. The frequency of sampling or readings must be sufficiently high to ensure an accurate representation of the entire truck volume. Consideration must be

given to both conditioning the flow stream and locating the probe or sampler. Flow conditioning to ensure turbulent mixing can be achieved through velocity control, piping configurations, or introduction of a mixing element upstream of the probe or sample point. Mid-pipe probe location should then provide for accurate sampling. API Manual of Petroleum Measurement Standards, Chapter 8.2, provides further details on flow conditioning, probe location, and sampling frequency.

ii) Manual Sampling

Manual grab sampling may be acceptable in situations involving a tight emulsion with little or no free-water separation in the truck. As with automatic sampling, the frequency of grab samples obtained during the unloading process must be sufficiently high to ensure an accurate representation of the entire truck volume. There is some question as to the validity of limited grab samples due to BS&W stratification with the truck. Limited data available to date have indicated that single-point grab sampling may be appropriate in heavy oil production scenarios where lease tank heating results in a tight, stable emulsion. Available data from conventional oil production scenarios, however, suggest that single or limited multi-point grab sampling may not be appropriate due to stratification of BS&W within the truck.

The use of manual sampling techniques such as truck tank thiefing (full height or intermittent) may also be acceptable. However, concerns exist over this procedure where stratification of water and emulsion or within the emulsion itself exists within the truck. The concern is that, in the presence of stratification, one unit of height at the bottom of the truck tank represents a significantly lesser volume than the same unit of height at the midpoint of the truck tank because of the elliptical shape of the tank. The resulting BS&W from a full height core thief therefore may not be representative of the entire load.

Lease tank thiefing is subject to similar stratification concerns (excluding the non-uniformity of the tank). These concerns can be reduced by locating any water - emulsion interface and obtaining bottom, middle, and top samples of the emulsion to determine an average cut. However, lease tank thiefing requires dedicated tankage per load to avoid mixing of product between deliveries.

It is clear that numerous problems may exist with manual sampling techniques. It is the expectation of the Board that the operator confirm the accuracy of the method employed, having regard for emulsion characteristics and stratification and BS&W consistency of the load. API Manual of Petroleum Measurement Standards, Chapter 8.1, provides further reference to manual sampling procedures.

iii) BS&W Determination

The most practical method for field determination of BS&W is by centrifuge as described in API Manual of Petroleum Measurement Standards, Chapter 10.4. The method includes the following components:

Heat - The sample should be heated to 60°C by heat both prior to and during centrifuging. Higher temperatures may be necessary for waxy crudes.

Solvent - Water-saturated solvent should be used to assist in obtaining a representative cut. Varsol, although not referenced in the API procedure, is a common solvent in Alberta. Care must be taken to ensure that the solvent is free of suspended water. Regular centrifuging of the solvent alone to confirm the absence of suspended water would be prudent practice.

Demulsifier - Enhancement of oil/water separation can be obtained through addition of an appropriate demulsifier. Demulsifier should be added to the sample in accordance with the manufacturer's recommendations.

Centrifuge - The centrifuge must be capable of spinning two or more centrifuge tubes at a speed resulting in a minimum relative centrifugal force of 500 gravities at the tip of the tube, as defined in the API manual.

The procedure for determining the BS&W of the sample is described in the API manual. Some deviations from this procedure may be appropriate; however, operators are expected to confirm that any deviation from these procedures does not compromise the accuracy of the BS&W determination. Operators are encouraged to adopt an appropriate standard procedure (ie. API or modification) and ensure that field personnel follow such procedures constantly.

The centrifuge method as described above is most appropriate for low BS&W samples as the resolution and accuracy of many centrifuge tubes decrease as BS&W increases. When the BS&W exceeds 25 per cent, it may be appropriate to consider an alternative procedure referred to as the "graduated cylinder" method. This method involves the collection and transfer of an entire sample to an appropriately sized graduated cylinder. Phase separation is achieved through the addition of demulsifier and retention in a heat bath until an oil/water interface is obtained. Centrifuging the oil layer is advised, with the BS&W of the sample calculated accordingly from the centrifuge and graduated cylinder data. As with the centrifuge method, operators are encouraged to adopt an appropriate procedure and ensure that field personnel follow the procedure constantly.

Implementation

As these systems and procedures are recommended guidelines, the Board is prepared to allow some deviation from these guidelines having regard for specific circumstances. In all cases, it is expected that the operator will determine which system, or modification to a system, is appropriate having regard for overall measurement and accounting accuracy. As indicated previously, receipt of trucked production at proration batteries represents a compromise between accuracy requirements and operational practicality. Circumstances may well exist where installation of dedicated treating facilities to process trucked production may be warranted. As a general guideline, the Board would be concerned about the need for a dedicated treating train where the volume of trucked emulsion exceeds 1000 cubic metres per month or 25 per cent of the flowlined emulsion. The decision to require this extra equipment would have to be made in light of the actual circumstances having regard for equity, royalty, and overall measurement accuracy considerations.

Effective immediately, the Board expects that these guidelines be considered for all new facilities intending to receive trucked oil production. The proposed measurement system for the trucked production must be fully addressed in the production facility application submitted to the ERCB in accordance with section 7.001 of the Oil and Gas Conservation Regulations. Operators should be reminded that commencement of the receipt of trucked oil production at an existing battery constitutes a modification to that battery. Operators are therefore required under section 7.002 of the Regulations to submit an appropriate application to the Board.

Although no formal submission to the Board is required, facilities currently accepting trucked oil production are expected to address this matter immediately. Modifications, where appropriate, are expected to be implemented by 1 April 1991 with the required documentation forwarded to the Board.

Questions or concerns regarding this matter should be directed to the Production Section of the Board's Drilling and Production Department at 297-3553 or 297-8448.

E. J. Morin, P.Eng.
Board Member

JUN 12 1990

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 90-7

TO: ALL OIL AND GAS OPERATORS

4 June 1990

1990 ADMINISTRATION FEE ON WELLS AND OIL SANDS PROJECTS

The Board has set the 1990 Administration Fee adjustment factor at 0.87 of the rate specified in sections 16.070 and 16.080 of the Oil and Gas Conservation Regulations and invoices will be mailed on 9 July 1990.

Industry associations have agreed to fund the sump sampling program and this cost will be included in the 1990 Administration Fees. This year's fee adjustment factor would have been approximately 0.844 if not for that commitment of funds.

Again, where the operation of a well is undertaken by a contract operator, the fee will be directed to the owner rather than the operator upon the written request of the owner. This request should include a complete description of the well and the name of the operator, and should be addressed to the attention of Mrs. T. Beyea and forwarded to our office no later than 2 July 1990.

R.T. Bording
Manager
Accounting

UNIVERSITY OF ALBERTA LIBRARY
0 1620 0571 5220

INFORMATIONAL LETTER IL 90-8

22 June 1990

TO: All Oil and Gas Well, Pipeline and Gas Plant Operators, Gas Utility Companies and NOVA Customers

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

Since 1980 the handling by the ERCB of the NOVA Corporation of Alberta (NOVA) pipeline applications with respect to industry issues has been in accordance with the ERCB Informational Letter IL 80-10 "Procedures and Economic Criteria for the Assessment of Future Alberta Gas Trunk Line Applications". In view of the deregulation of the gas industry, NOVA's major system expansion program and its potential impact on the cost of service, the ERCB initiated a review to see if changes are required to IL 80-10. Board staff met with and received comments and inputs on the matter from representatives of NOVA, the Canadian Petroleum Association, the Independent Petroleum Association of Canada, the Small Explorers and Producers Association of Canada, the Alberta Petroleum Marketing Commission, and three major shippers. Considering the advice of the industry, the Board concluded that the attached new procedures would be more relevant to the current situation and should replace those set out in IL 80-10. The attached procedure for review of NOVA facilities by industry will be adopted immediately.

It should be noted that these new procedures deal only with industry concerns related to the economic and orderly development of the NOVA system and the impact on its cost of service. Landowner/occupant, other public interest, or environmental concerns will be dealt with in accordance with normal ERCB procedure to ensure that any person whose rights may be directly and adversely affected would have the opportunity to comment on the matter.

Should you have any questions, please contact Mr. Ed Fox, Manager of the Board's Pipeline Department, at 297-8133.

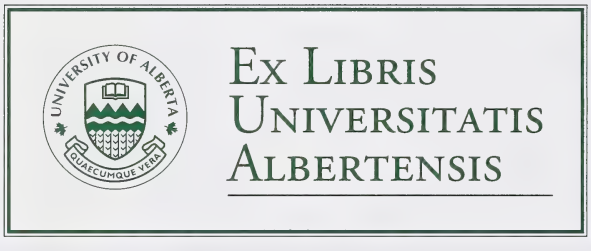
This Information Letter supersedes and replaces IL 80-10.

<signed by>

F. J. Mink
Board Member

Attachment

Attachment to Informational Letter IL 90-8


UNIVERSITY OF ALBERTA
QUAECUMQUE VERA
EX LIBRIS
UNIVERSITATIS
ALBERTENSIS

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

The Board will use the following procedures for assessing NOVA pipeline applications.

A

NOVA is required to establish a committee and appropriate sub-committees with representation from NOVA, industry associations such as the Canadian Petroleum Association, the Independent Petroleum Association of Canada, the Small Explorers and Producers Association of Canada, and other interested parties for the purposes of facilitating the effective, efficient, and timely exchange of information among involved parties and of addressing NOVA's long-term planning and policy issues. Board staff will participate as observers on matters that are within ERCB jurisdiction.

B

NOVA is required to make industry aware on a regular basis of its upcoming facility additions and major modifications at an early stage in its design cycle time. Presently, each design cycle time is approximately 27 months from the deadline date for NOVA customers to sign their firm service requests through preliminary design, detailed design, regulatory approval, and construction to the in-service date of all resulting facility additions and major modifications to meet such service requests.

C

NOVA will use a two-stage application process. The first stage is the filing with the ERCB of an annual preliminary overall system plan (Annual Plan) containing all planned facility additions and major modifications. The second stage is the filing of the final technical, cost, routing/siting, land, environmental, and other information required to complete the application for each facility contained in the Annual Plan.

D

The Annual Plan will be filed as early as possible in the design cycle but not later than May of each year.

E

The Annual Plan will contain sufficient information on the need, rationale, and justification for the proposed facility additions and major modifications, and will include but not be limited to

(a) system demand outlook,
(b) system reserves and deliverability on an areal basis,
(c) assumptions, design criteria, and methodology,
(d) economic criteria,
(e) preliminary sizing of each facility,
(f) preliminary route/site for each facility,
(g) preliminary cost estimate and construction schedule for each facility,
(h) impact on NOVA's cost of services due to the implementation of the Annual Plan, and
(i) long-term plan and the impact resulting from the implementation of the Annual Plan on the long-term plan.

F

NOVA is required to publish a notice, soon after the Annual Plan is filed, in major newspapers advising industry that copies of the Annual Plan can be obtained from NOVA for review. The Board will also have a copy of the Annual Plan placed at its information centre for public viewing.

G

UNIVERSITY LIBRARY
UNIVERSITY OF ALBERTA

The Board staff will review the Annual Plan and may request additional information. Such a review could include a technical review with industry participation.

H

Any interested industry parties who have concerns or questions on any generic issues or on any individual facility or group of facilities in the Annual Plan must contact NOVA directly for resolution. If any of these concerns cannot be satisfactorily resolved, the parties may then submit them to the Board within a reasonable period. The Board will defer the consideration of concerns on individual facility or group of facilities to the second- stage application. With respect to the concerns on generic issues in the Annual Plan, the Board may call a meeting of interested parties to discuss them. All interested parties will be notified.

I

NOVA will file the second-stage material required to complete each facility application referred to in item (C) as soon as that information is available.

J

In assessing each facility application with respect to the need of notice, the Board will have regard for its review of the application and the Annual Plan, submissions received respecting the Annual Plan, concerns submitted regarding the facilities, and any significant changes in facts or circumstances between the filing of the Annual Plan and the application. If every aspect referred to above is deemed by the Board to be satisfactory, the application may be approved without a notice for objection, and if not, a notice will be issued. The notice for objections would typically be issued for an application with a capital cost in excess of $10 million.

K

In certain instances where submissions have already been filed or the Board is aware that objections will likely be filed, it may go directly to public hearing. Additionally, where valid objections are filed as a result of notice, a hearing will be held.

L

Any facility application filed for approval that is not contained in the Annual Plan must include, in addition to material referred to in item (C) for the second-stage application, information on

(a) the purpose and necessity for the proposed facility,
(b) the reasons why it was not included in the Annual Plan,
(c) the impact on the Annual Plan,
(d) the impact on NOVA's cost of service, and
(e) the impact on NOVA's long-term plan.

Any application of this nature will be assessed on its own merit and advertised if required.

INFORMATIONAL LETTER ADDENDUM TO IL 90-8

TO: All Oil and Gas Well, Pipeline and Gas Plant Operators, Gas Utility Companies and NOVA Customers

4 April 1994

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

In accordance with Item J of Informational Letter IL 90-8, a notice for objection has been issued by the ERCB for each NOVA pipeline application with a capital cost in excess of $10 million. Since the issuance of the IL in June 1990, approximately 30 such notices have been routinely published. To date only one objection, which related the the Pacific Gas Transmission Expansion Project, has been filed.

Nova has reviewed the merit of this procedure and has consulted members of the Facilities Liaison Committee, the CAPP/NOVA Committee and the Board staff. They have concluded that the current practice of routine Publication of Notice provides little added value and its elimination would have no adverse impact on industry awareness of, and opportunity to object to, major NOVA facility applications. There would be the advantages of reducing application processing time and savings on costs of advertising. Consequently, NOVA has made a request to the Board to discontinue this practice.

The Board has reviewed the matter, noting the agreement of the affected parties, and has decided to grant this request. Therefore, the last sentence in Item J of the IL "The notice for objections would typically be issued for an application with a capital cost in excess of $10 million" is deleted effective immediately.

Should you have any questions, please contact the undersigned at 297-8133.

<signed by>

K. G. Sharp, P.Eng.
Manager
Pipeline Department

Return to top of this Informational Letter

Return to main page for accessing ILs, IDs, and GBs

Links to other pages on our website:

| About EUB | New | Catalogue | Order Form | Legislation | ILs, IDs, GBs | WWW | Copyright |

Last modified Tuesday, 07-Jan-97 10:39:57]>

Please direct any questions or comments to: aeubsys@mail.eub.gov.ab.ca

AL INST
c 12

CANADIANA
APR 26 1994

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

ADDENDUM TO
IL 90-8

To: All Oil and Gas Well, Pipeline and Gas Plant Operators, Gas Utility Companies and NOVA Customers

4 April 1994

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

In accordance with Item J of Informational Letter IL 90-8, a notice for objection has been issued by the ERCB for each NOVA pipeline application with a capital cost in excess of $10 million. Since the issuance of the IL in June 1990, approximately 30 such notices have been routinely published. To date only one objection, which related to the Pacific Gas Transmission Expansion Project, has been filed.

NOVA has reviewed the merit of this procedure and has consulted members of the Facilities Liaison Committee, the CAPP/NOVA Committee and the Board staff. They have concluded that the current practice of routine Publication of Notice provides little added value and its elimination would have no adverse impact on industry awareness of, and opportunity to object to, major NOVA facility applications. There would be the advantages of reducing application processing time and savings on costs of advertising. Consequently, NOVA has made a request to the Board to discontinue this practice.

The Board has reviewed the matter, noting the agreement of the affected parties, and has decided to grant this request. Therefore, the last sentence in Item J of the IL "The notice for objections would typically be issued for an application with a capital cost in excess of $10 million" is deleted effective immediately.

Should you have any questions, please contact the undersigned at 297-8133.

K. G. Sharp, P.Eng.
Manager
Pipeline Department

CANADIANA

JUL 23 1990

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 90-9

TO: All Oil and Gas Operators,
Straddle Plant Operators, and
Petrochemical Facility Operators

16 July 1990

GOVERNMENT OF ALBERTA ETHANE POLICY IMPLEMENTATION PROCEDURES

1 INTRODUCTION

On 21 August 1987, the Government of Alberta issued a Policy Statement on Ethane and by his letter of the same date, The Honourable Dr. N. Webber, then Minister of Energy, requested that the Board consider and report on the ethane policy with particular reference to several specific matters. (Appendix 1 includes the 21 August 1987 ethane policy statement and Dr. Webber's letter.) Following a public inquiry to hear the views of all interested parties, the Board issued Report D 88-D[1], containing its recommendations respecting implementation of the policy. Subsequently, on 14 October 1988, the Government issued a statement on Implementation of an Ethane Policy in Alberta and a news release. These are included in Appendix 2.

The purpose of this informational letter is to set out how the Board will implement the policy. The Board's intent is to provide sufficient detail in this letter so that all parties will have a full understanding of the procedures. It deals with the facilities that are subject to the ethane policy, the principles and methods for determination of the threshold volume, adjustments which may be necessary to the threshold volume, the monitoring of ethane available at the straddle plants and a system to ensure the threshold volume is maintained, the duration of the policy, the means of establishing the price to be paid for reinjected ethane, the procedures for handling applications for new field plants for recovering ethane, and the conditions pertaining to ethane that will be included in future field plant approvals.

The Board circulated a draft of this informational letter to industry and on the basis of the responses received, made additional changes to the proposed implementation procedure. Where responses related to policy principles, they were referred

---

1 Report D 88-D, Alberta Ethane Policy, Report on Implementation. Energy Resources Conservation Board. April 1988.

to the Government for consideration. Subsequently and after consultation with certain parties, the Government made further changes to its policy, including a termination date.

Although this letter sets out detailed procedures which will be utilized if needed, the Board continues to be of the view expressed earlier that sufficient ethane should be available over the term of the policy to satisfy fully Alberta requirements, including an expanded ethylene industry.

2 ETHANE FORECAST

The basis of the administration of the ethane policy will be an annual ethane forecast which will be issued in about October of each year, beginning in 1990. The forecast will project gas flows and ethane contents for the major gas transmission pipelines in the province on which the existing straddle plants are located. In this manner, the expected volume of ethane available at each straddle plant inlet will be estimated. Each year, the annual forecast will be a 10-year projection with the first year done on a monthly basis and the remaining 9-year period done on an annual basis.

The Board will invite written submissions from involved parties respecting gas throughputs and ethane content. The first such requests will be made later in July 1990, with respect to monthly estimates for 1991 and annual estimates for the period 1992 to 2000. In subsequent years, industry submissions will likely be requested about a month later. The Board will make available, through its Information Services Section[2], all written submissions that it receives so that interested persons may peruse them. The submissions will be made available immediately after the deadline for receiving them which will be about 1 month after the Board sends out its request for submissions.

3 FACILITIES SUBJECT TO THE POLICY

Appendix 3A lists those field plants, and their corresponding approved ethane extraction capacities, which are permanently exempt from the provisions of the ethane policy. These field plants were approved to recover ethane prior to the Government's announcement of its ethane policy on 21 August 1987. The

---

2 Located at the Board's head office, main floor, 640 - 5 Avenue S.W., T2P 3G4.

exemption applies only to the ethane extraction capacity of each plant at 21 August 1987, as determined by the Board. Any increases that occur in ethane extraction capacity, above the capacities listed in Appendix 3A, will be subject to the ethane policy.

Field plants for which approval for the extraction of ethane was issued after 21 August 1987 will be subject to the ethane policy. However, all new or existing field plants recovering ethane but delivering the residue gas to a gas reservoir cycling scheme, an enhanced oil recovery scheme, or otherwise not delivering gas to the existing straddle plant system will be exempt from the policy until they cease such operations and deliver their residue gas to the currently existing straddle plant system. Appendix 3B lists such existing plants and their approved capacities.

Where a plant for which approval to extract ethane was issued after 21 August 1987 delivers only a portion of its sales gas to the existing straddle plant system, it would be subject to the ethane policy to the extent of such gas deliveries.

Appendix 3C lists the straddle plants comprising the straddle system today, which will be designated by the Board in accordance with section 22.1 of the Act, and their base-year[3] specification ethane production and recovery efficiencies. The Board calculated the base-year recovery efficiencies for the straddle plants using the average monthly ethane concentration data provided at the inquiry and the gas throughput and ethane production data on file with the Board (except for the combined Amoco Canada Petroleum Company Ltd. (Amoco) Empress I and II plants where individual plant data were provided subsequently to the Board by Amoco). Changes were made to the actual production data for the combined Amoco Empress I and II plants to correct for reporting errors. In addition, the Board adjusted the recovery efficiency for the Amoco Ellerslie plant to account for certain months in the base period when ethane recovery was unusually low and, in the Board's view, did not reflect the plant capability. A minor adjustment was also made to the ANG Cochrane plant data to reflect approved throughputs.

---

3 The period from 1 September 1986 through 31 August 1987 has been chosen as the base year for administration of the threshold volume. The base-year specification ethane production will be used to allocate the overall threshold volume to designated straddle plants when the need arises. The base-year recovery efficiencies are used to convert the threshold volume from an outlet to an inlet basis.

4 DETERMINATION OF THE THRESHOLD VOLUME

As stated in the 14 October 1988 policy implementation statement, "the ERCB will set a threshold volume at a level that will meet the demonstrated, sustained operational needs of the existing ethylene plants, after the planned debottlenecking".

The actual 1989 calendar-year ethane consumption of AGE I and II, the two existing ethylene plants at the time of the policy announcements, will be used to determine the threshold volume. The usage was 5.309 x 10^6 cubic metres[4] per year (m^3/yr) or 14 746 cubic metres per stream day (m^3/d) expressed on a pure ethane[5] basis. The Board has rounded this daily usage to 14 750 m^3/d for the threshold volume calculation which is detailed in Appendix 4. Because the Board has used on-stream days for calculating the threshold volume, reinjection would not be required during periods when AGE I and II are not operating, should the threshold volume be breached.

The threshold volume has been expressed on an average stream day basis. It is calculated by adding to the actual 1989 requirements of AGE I and II, the minimum Cochin pipeline buffer requirement, deemed by the Board to be 500 m^3/d, and then subtracting the contributions of those field plans under

---

4 All ethane volumes used in this letter are in cubic metres of liquid ethane. The conversion factor from cubic metres of liquid ethane to barrels of liquid ethane is approximately 6.33 barrels per cubic metre.

5 The Board has decided to use pure ethane throughout this document because the ethane available to the straddle plants will be calculated on the basis of pure ethane. Specification ethane contains approximately 94 per cent pure ethane; hence, pure ethane volumes are about 6 per cent less than specification ethane volumes.

6 The specification ethane production from the Shell field plants was converted to pure ethane using the original application material balance and differs from the 94 per cent pure specification ethane given in footnote 5.

contract to The Alberta Gas Ethylene Company Ltd. (AGEC) at the time the policy was announced, the Shell Canada Limited (Shell) Waterton and Jumping Pound plants. Their combined base-year ethane production rate[6] was 940 m^3/d. The result of 14 310 m^3/d represents the required volume at the outlet of the straddle plant system.

In accordance with section 22.1 of the Act, the ethane policy will terminate on 30 June 2008. Since the policy will extend beyond the period for which the ethane recovered by the straddle plant system is contractually almost totally dedicated to AGEC, it is possible that ethane from designated straddle plants may eventually go to different purchasers. For this reason, the Board has concluded that it may be necessary in future to allocate the total threshold volume among designated straddle plants and has included this breakdown in Appendix 4. This allocation is based on each designated straddle plant's base-year ethane production as shown in Appendix 3C. For this allocation the two Amoco Empress plants are treated as one plant because only one set of operating statistics is reported to the Board.

The Board allocated the total outlet threshold volume to each straddle plant as described above, then divided each plant's outlet threshold volume by its base-year recovery efficiency to determine the inlet threshold volume for each plant. The Board then totalled the individual plant inlet threshold volumes to arrive at a total inlet threshold volume of 21 272 m^3/d.

The Board intends to administer the policy on an overall basis using this total threshold volume as long as the existing ethane purchase contracts of the designated straddle plants remain in effect. Only if a straddle plant decontracts from AGEC and it appears necessary will the Board break out the threshold volume by individual plant and administer on that basis. Even in that situation, the Board intends to use a composite number for all of the Empress plants until it becomes necessary to break out the individual Empress plant threshold volumes. The Board believes that this will provide greater flexibility to the Empress plant operators and will not complicate the administration of the threshold volume.

5 ADJUSTMENTS WHICH MAY BE NECESSARY TO THE THRESHOLD VOLUMES

The individual straddle plant threshold volumes have been calculated on the basis of the base-year plant recovery efficiencies. The Government wishes to have a system which would adjust the calculated threshold volume should future upstreaming

of any of the straddle plants cause the ethane recovery efficiency of the plant, as it existed in the base year, to be significantly affected. In order to do this, the Board will prepare a set of recovery efficiency curves for each straddle plant as they existed in the base year. Such curves will allow the Board to assess whether future upstreaming is not only reducing the ethane available at the straddle plant, but is also reducing the ethane content or affecting other characteristics of the gas stream such that the plant, as it existed in the base year, would have a significantly lower ethane recovery efficiency. The curves will be prepared in consultation with the straddle plant owners and would account for factors that the Board believes could significantly affect the recovery efficiency.

The Board believes the straddle plant owners must continue to carry the risk for reductions in ethane available at the straddle plants caused by reduced gas flows and reduced ethane content in the gas not related to upstreaming or reduced plant efficiencies due to other non-upstreaming factors. However, if a straddle plant owner can demonstrate to the Board's satisfaction that the extraction of ethane by field plants approved after 21 August 1987 has reduced the ethane content of or otherwise altered the gas streams passing through a straddle plant such that the recovery efficiency of the plant, as it existed in the base year, has been significantly reduced, the Board would be prepared to adjust the calculated threshold volume. It would do so on the basis of the above-noted recovery curves. Appendix 5 illustrates how such an adjustment might be made to the threshold volume; however, the actual details of the calculation would depend upon the circumstances at the time.

Such an adjustment, based on the base-year recovery efficiency curves, would be potentially available whether or not the straddle plant had been upgraded in the meantime, so it should provide a method which would not be materially altered by expansion or upgrading of existing straddle plants.

The onus for initiating a possible future change to a threshold volume would rest jointly on the straddle plant operators and purchasers of straddle plant ethane, but the Board would provide an opportunity for all affected parties to have input.

With respect to the field plant contribution to the feedstock requirements of AGE I and II, the Board considers it AGEC's responsibility to contract to replace the field plant contribution in future should it become necessary. Therefore, the Board will not adjust the threshold volume if the base-year

field plant contribution changes, for any reason, from the 940 m^3/d used in the calculation.

6 MONITORING OF ETHANE AVAILABLE TO THE STRADDLE PLANTS

For purposes of administering the policy, and to enable the Board to monitor the total ethane available to the straddle plant system, the Board will require each designated straddle plant and each field ethane plant subject to the policy to report the gas throughput, the average ethane content of the inlet gas, and the ethane production volumes on a monthly basis. The ethane production volumes reported by field ethane plants will be expressed in terms of the volumes of ethane mix and the equivalent volumes of pure ethane. All reports are to be submitted to the Board's Gas Department by the 23rd day of the following month. If on-going experience indicates that the reports are not needed, or that changes should be made, this requirement will be altered or cancelled.

Although the initial year of the Board's annual 10-year ethane availability forecast will be prepared on a monthly basis, the basis for enforcement of the threshold volume will be half of the calendar year. Based on the expected pattern of ethane availability as portrayed in the monthly forecast for the upcoming year, the annual threshold volume will be apportioned to each calendar-year half, beginning with the period January to June, inclusive. While this approach would not distribute the threshold volume on a seasonal basis, each calendar-year half would include a part of the year when gas flows are typically high and a part of the year when gas flows are typically low. Thus, these would tend to balance each other out. In addition, increased use of storage may be required to maintain adequate availability of ethane to meet feedstock requirements during that period in a calendar-year half when monthly inlet ethane volumes are below the average for the calendar-year half but the average ethane availability in the calendar-year half exceeds the threshold volume. The Board expects that under the policy, ethane storage capacity would be more effectively used to balance differences related to seasonal gas flow.

The Board will monitor the ethane supply in each calendar-year half on a monthly basis using the data provided by the straddle plant operators. In this way, if a breach of the threshold volume develops that was not anticipated when the ethane forecast was prepared, or if a larger or smaller than expected breach develops, the Board will be able to effect a quicker response and

thereby minimize any adverse impacts on the straddle system and on field ethane plants subject to reinjection. (This is discussed in more detail in Section 7.)

7 MAINTENANCE OF THE THRESHOLD VOLUME

In administering the maintenance of the threshold volume, the Board sees the possibility of three cases occurring:

Case 1: If no breach of the overall threshold volume were forecast during either half of the subject calendar year, no further Board involvement would be required for that year except to announce this fact and monitor the actual ethane availability throughout the year.

Case 2: If the forecast indicates a breach of the overall threshold volume would occur in either half of the coming year, the Board would follow the Maintenance Procedures outlined below.

Case 3: If the ethane availability forecast suggested that there would be no breach of the threshold volume during either half of the subject calendar year, but a breach did occur, or if a breach occurred which was larger or smaller than expected, the Board would follow the Adjustment Procedures outlined below.

In general, where the threshold volume is anticipated to be breached (Case 2) or is unexpectedly breached (Case 3), the order in which ethane would be called upon to satisfy the breach would be: (1) royalty ethane, (2) working interest ethane from plants subject to the policy which is not supplying petrochemical needs, and (3) other working interest ethane from plants subject to the policy.

The Board understands that the Government could draw upon all plants where there is a royalty obligation with respect to ethane. The Government may elect not to take its royalty ethane in kind, in which case it would meet its obligations to supply the first tranche of ethane under the policy by providing a credit of the value of ethane affected by the policy against royalties accruing to the Crown. In addition, a field plant operator, required to reinject ethane under the policy, may choose to by-pass gas around the ethane recovery unit to satisfy a reinjection order rather than actually reinject ethane.

The Board intends to adjust its enforcement of the threshold volume to meet circumstances that may occur in future. In a situation where the ethylene plants were not operating or were

operating at significantly reduced throughput, the Board would alter or cancel any ordered maintenance of the threshold amount, as appropriate.

7.1 Maintenance Procedures

- The period for administering the threshold volume would be one-half of the calendar year beginning with January to June.

- 1 September would be the deadline for receiving industry submissions respecting the ethane availability forecast.

- 1 October would be the deadline for the Board to prepare and make available its ethane availability forecast. This forecast would show the total ethane available, and would emphasize the first year but cover 10 years. The Board would provide an indication of whether it expected a shortfall in the overall threshold volume in the upcoming year and, if so, in which half of the year and by how much. If there were no shortfall expected, no further Board involvement would be required, except for monitoring.

- If the forecast indicated a shortfall, the Board would advise the Crown of the expected shortfall so that the Crown could take action to have its royalty share of field plant production of ethane made available to the operators of the designated straddle plants. If the amount of royalty ethane were insufficient to satisfy the shortfall, the Board would then issue an initial directive indicating the amount of the expected shortfall and the volume that must be provided on an average day basis throughout the particular half year to maintain the threshold volume. A deadline of 15 December or the nearest working day to 15 December would be set for involved parties to negotiate the sales of the needed ethane make-up volumes. This would also be the deadline for the straddle plant owners to advise the Board of the results of the negotiations. If the negotiations were successful, no further Board involvement would be necessary unless on-going monitoring revealed problems requiring the Board's involvement.

- If the negotiations were unsuccessful, the Board would order reinjection from involved upstream plants, in the priority order noted earlier, to commence on the first day of any affected calendar-year half at the average daily rate required to maintain the threshold volume. The Board would monitor throughout the calendar-year half and where necessary, follow

the Adjustment Procedures. Should a voluntary agreement be reached after the Board had issued its reinjection order, the Board would be prepared to rescind its order.

- The Board recognizes that there are other options available, such as exchanging ethane among producers or the use of compensation, that might bring about more effective utilization of ethane while still meeting the objective of maintaining the threshold volume. In such situations where it was clearly advantageous to do so and where all parties agreed, the Board would accept a variation.

- The Board would retain the authority to designate the point of reinjection where necessary to ensure that reinjected ethane becomes available to the designated straddle plants. However, the option would be available to the operator(s) of the field plant(s) to supply the ethane in kind directly to the straddle plant at a mutually agreed-to location and avoid reinjection. The volume of ethane to be supplied in kind would generally be the shortfall in the inlet threshold volume times the base-year recovery efficiency for the straddle plant(s) affected to convert the inlet volumes to outlet volumes. However, the producer choosing to supply ethane in kind would be required to absorb related effects on the straddle plant, such as a significant reduction in ethane recovery efficiency caused by the reduced ethane content of the inlet gas at the relevant straddle plant.

- Where the Board must allocate make-up volumes among two or more upstream plants within the order of reinjection priority noted earlier, it will do so on an ethane production-history prorated basis using the preceding 12-month period.

- Where a shortfall in the threshold volume is indicated and voluntary negotiations eliminate part but not all of the indicated shortfall, and where the shortfall must be allocated to more than one upstream plant, the Board will have regard for the volumes voluntarily made available to the straddle plant owners, in making the allocation.

- The Board will allocate the overall threshold volume to individual straddle plants for administration on that basis only if an existing ethane purchase contract of a designated straddle plant terminates and, in the Board's view, it appears necessary to make such an allocation.

7.2 Adjustment Procedures

- Where monitoring demonstrates that there was a breach of the overall threshold volume in any calendar-year half for which one was not expected, and where the breach was due to upstreaming, the Board will immediately advise the Crown so that royalty ethane can be made available commencing in the following month. If royalty ethane is insufficient to satisfy the shortfall, the Board would then issue an order for the shortfall to be made up beginning in the month following the discovery of the shortfall. The Board would hope that such unexpected shortfalls would be made up through voluntary arrangements and, where such were put in place, it would rescind the order.

- There may be instances where a breach of the overall threshold volume due to upstreaming was greater than had been forecast, and monitoring showed a shortfall even though reinjection or supply of ethane was occurring. This shortfall will be treated the same as in the preceding paragraph and the Board would order it to be made up commencing in the calendar-year half of its discovery.

- Where reinjection or supply of ethane was ordered by the Board and monitoring showed the amount reinjected or supplied was greater than needed, the Board would order a reduction in this amount commencing in the month following discovery. Any excess reinjection which has occurred as a result of a Board order or a voluntary agreement reached as a result of the Board advising of a threshold volume shortfall and which is still outstanding at the end of the calendar-year half, would be subtracted from the amount of reinjection required in the next calendar-year half.

- If by-passing of gas or reinjection of recovered ethane were to occur at a straddle plant during a period when a field plant was reinjecting ethane under a Board order or under a voluntary agreement in lieu of a Board order, the Board would be prepared to reconsider the volume of ethane to be reinjected or rescind its order altogether, if appropriate. Depending upon the amount and duration of the by-passing or reinjection at the straddle plant, the Board may decide that the volume of ethane remaining to be reinjected during the period could be adjusted downward, or that the volume of ethane already reinjected could be carried forward by the field plant operator as a credit toward reinjection requirements in the next calendar-year half.

- If the ethylene plants were either not operating or operating at rates substantially below their capacities while reinjection was occurring under a Board order or under a voluntary agreement in lieu of a Board order, the Board would be prepared to reconsider the volume of ethane to be reinjected or rescind its order altogether, if appropriate.

- If an unforeseen emergency were to occur, for example a force majeure incident at one of the plants named in an order, the Board would exercise its discretion in determining the amount and timing of any reinjection that might be required.

8 POLICY DURATION

Commencing 1 July 2004, the threshold volume will be reduced by 20 per cent per year until 1 July 2008 when it will become zero and the policy will terminate.

9 PRICE DETERMINATION FOR REINJECTED ETHANE

The price to be paid for ethane that must be reinjected or supplied to maintain the threshold volume will be determined through negotiation among the parties involved. If voluntary negotiations fail, then the price will be determined through arbitration. Since the possibility that reinjection will be required and arbitration invoked is very remote, and since it is impossible to anticipate the market circumstances in which arbitration would occur, further details of the arbitration will be provided if and when the need arises.

10 FIELD PLANT APPLICATION PROCEDURES AND CONDITIONS TO BE INCLUDED IN APPROVALS

In general, an application for a new field plant to recover ethane will have similar information requirements and be handled in a manner similar to other applications for gas processing plants. However, any approval issued for a plant recovering ethane will contain a condition making such a plant subject to the ethane policy as implemented. The wording of the clause would be similar to the following:

"The Operator is subject to any order of the Board issued pursuant to section 22.1 of the Oil and Gas Conservation Act."

The procedures that the Board will use for handling field plant ethane-extraction applications fall into two categories.

Category 1

Where the Board is satisfied that conservation, social, and environmental requirements are met, that the applied-for plant is in the public interest and there have been no objections to the plant in these respects after publication of notice, and where the most recent 10-year ethane forecast indicates that operation of the plant would not result in the threshold volume being breached over the period of the forecast, the Board would approve the application without a hearing. The approval would include the previously cited condition requiring the operator of the field plant to comply with any order issued under section 22.1 of the Oil and Gas Conservation Act. (It is important to note that an approval to recover ethane is a conservation project falling under section 26 of the Oil and Gas Conservation Act. Such an approval is not and should not be construed as an authorization to remove ethane from the province. Removal permits are required under the provisions of the Gas Resources Preservation Act.)

The Board would notify all parties known to be interested in extraction of ethane, of the approval of the field plant application. Parties directly affected by such an approval would have the right, under section 43 of the Energy Resources Conservation Act, to request a hearing in order to have their concerns heard by the Board. If an intervener requested a hearing even though the ethane supply forecast indicated that there would be no breach of the threshold over the 10-year forecast period, the onus would be on that intervener to demonstrate why issuance of the approval should be reconsidered.

Category 2A

If the Board is otherwise satisfied with an application, but the most recent ethane forecast indicates there would be a breach of the threshold volume over all or most of the 10-year forecast period, the Board would deny the application unless the applicant requested that a hearing be held. In such a case, the onus would be on the applicant to demonstrate why the plant should be approved even though much of the ethane to be recovered by the field plant, or its equivalent volume from other field plants, would probably have to be reinjected.

Category 2B

In the same situation, but where the most recent ethane forecast indicates there would be a breach of the threshold volume in only a few years over the forecast period, the Board would either go directly to a hearing or advertise the application for

objections. If objections were received in response to advertising, the Board would call a hearing.

Parties interested in being kept informed on ethane matters should ensure that their names are included on the Board's Ethane Mailing List. This can be done by sending a letter to the Administrative Services Department, ERCB.

Any questions regarding the matters outlined in this letter may be directed to the Manager or Assistant Manager of the Board's Gas Department at 297-8506 or 297-7322, respectively.

G. J. DeSorcy
Chairman

APPENDIX 1 GOVERNMENT OF ALBERTA POLICY STATEMENT ON ETHANE

- Letter dated 21 August 1987 from The Honourable Dr. N. Webber, Minister of Energy.
- Policy Statement on Ethane dated 21 August 1987.

ENERGY

Office of the Minister

228 Legislature Building, Edmonton, Alberta, Canada T5K 2B6 403/427-3740

RECEIVED AUG 2 1 1987

August 21, 1987

Mr. G.J. DeSorcy
Chairman
Energy Resources Conservation Board
640 - 5 Avenue S.W.
Calgary, Alberta
T2P 3G4

Dear Mr. DeSorcy:

The Government of Alberta has recently announced a policy with respect to ethane. A copy of the policy statement is attached.

The policy statement indicates that the Government intends to amend the legislation to require that approvals of upstream ethane plants be made subject to the condition that if ethane volumes at the straddle plants fall below certain 'threshold volumes', the upstream plants will be obliged to reinject ethane to the straddle plant system to maintain threshold volumes or to supply ethane at the incremental cost of extraction of the straddle plant system.

The Government requests that the Energy Resources Conservation Board include such conditions in all approvals of upstream ethane extraction facilities, but otherwise ensure expeditious processing of applications.

The statement indicates the need for further consultation with the industry and consideration of the policy, its implementation, and any amendments to the legislation required to implement the policy.

I am hereby requesting that the ERCB consider and report on the ethane policy, with particular reference to the following specific matters:

1. The determination of the ethane facilities which should be affected by or be part of this policy.

2. The principles that should be used in determining the threshold volumes and the actual volumes thereby determined.

. . . / 2

3. The determination of the procedures for requiring and the mechanism for ensuring re-injection or supply of ethane to the straddle plant system.

4. Procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities.

5. The existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction and potential linkages with threshold volumes.

6. Any legislative changes required to implement the policy.

7. Any other relevant matters.

I look forward to a timely report on this matter because, as you are aware, there are currently a number of active applications to recover ethane at field plants. If possible, the report should be available by November 15, 1987. If this is not feasible, I would appreciate being kept informed as to when I may expect your report.

Sincerely,

Neil Webber

Neil Webber
Minister

Attachment

August 21, 1987

POLICY STATEMENT ON ETHANE

Over the last ten years a world-scale ethane based petrochemical industry has located and expanded in Alberta. Development of the industry represents a major success in terms of the Government's objectives of economic diversification and maximum upgrading of Alberta's resources within the Province. This development reflects the industry's recognition of the stable and supportive business environment in Alberta and the long-term, secure, market-priced supply of the essential petrochemical feedstocks.

The Alberta Government also recognizes the important economic contribution of the oil and gas industry to Alberta and the investments it has made in support of a major objective of the Alberta Government, the encouragement of optimal resource development. As part of this objective, Enhanced Oil Recovery (EOR) by hydrocarbon miscible floods has been specifically encouraged by incentives under section 4.2 of the Petroleum Royalty Regulation.

The feedstock of the existing ethylene-based petrochemical industry is ethane, principally extracted at "straddle plant" facilities located at Empress and Cochrane, Alberta. During the last decade, there has been increasing demand for field extraction of ethane to provide solvent for enhanced oil recovery and, potentially, to provide feedstock for petrochemical facilities. It has been stated that the construction of ethane extraction capacity upstream of the straddle plants, which removes ethane which would otherwise be available at the straddle plants, could affect the availability of adequate supplies of ethane at the straddle plants to meet current petrochemical obligations.

Applications to the Energy Resources Conservation Board (ERCB) to recover ethane at field plants upstream of the straddle plant system have resulted in numerous lengthy public hearings. As a result, the Government has received numerous representations from the petrochemical, gas-producing, straddle-plant and enhanced oil recovery industries to take some action to improve the situation.

The Alberta Government believes that sufficient ethane is and will be available in the province to meet foreseeable demand for ethane for both petrochemical feedstock and EOR solvent. However, continued upstreaming has the potential to jeopardize straddle plant ethane supply, especially during periods of low natural gas flows through the straddle plants.

Therefore, the Alberta Government is announcing measures to maintain a functioning market in ethane wherein both the petroleum and petrochemical industries will have access to adequate and competitive sources of ethane supply and the incentive for further development of ethane-related activity in the province.

The Alberta Government re-affirms its policy to ensure that ethane will be available for petrochemical use in Alberta. More specifically, the Government will take action to require the Energy Resources Conservation Board to include in further approvals of upstream ethane extraction facilities a condition that the upstream plants will be required to reinject or supply to the petrochemical industry, which depends on straddle plant ethane, sufficient ethane to maintain the "threshold volumes" required by the petrochemical industry.

If ethane availability at the straddle plants drops below the "threshold volumes", then the ERCB will direct upstream plants subject to the condition to reinject or supply (at the incremental cost of ethane extraction at the straddle plants) ethane to restore the threshold level.

In this manner, the petrochemical industry is assured that its straddle plant supply cannot fall below "threshold volumes" . With this security of supply the petrochemical industry can proceed with investment in additional ethylene capacity and in enhancing ethane extraction efficiency at the straddle plants.

The policy also means that the petroleum industry can proceed with upstream ethane extraction, in addition to other non-upstreaming facilities, subject only to more expeditious regulatory approval by the ERCB and the condition that they may be required to reinject or provide ethane to the straddle plants. As a result of this policy such approvals

should become routine and not be subject to the major upstreaming hearings experienced between 1981 and 1986.

In order to address the administrative issue of levying royalty on ethane from field deep cut extraction plants, which is currently royalty liable, but for which there is no liquid royalty prescribed, the Alberta Government will introduce a royalty on liquid ethane. As with all royalties, the government may elect to take the royalty in kind.

The Alberta Government wishes to have further consultation with the industries affected concerning the policy and the procedures for implementing the policy.

For this reason the Alberta Government will request the ERCB to inquire into the following specific matters:

1. The determination of the ethane facilities which should be affected by or be part of this policy.

2. The principles that should be used in determining the threshold volumes and the actual volumes thereby determined.

3. The determination of the procedures for requiring and the mechanism for ensuring re-injection or supply of ethane to the straddle plant system.

4. Procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities.

5. The existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction and potential linkages with threshold volumes.

6. Any legislative changes required to implement the policy.

7. Any other relevant matters.

APPENDIX 2 GOVERNMENT OF ALBERTA IMPLEMENTATION STATEMENT ON ETHANE POLICY

- News release announcing Ethane Policy Implementation.
- Statement on Implementation of an Ethane Policy in Alberta dated 14 October 1988.

Alberta NEWS RELEASE

GOVERNMENT OF ALBERTA

FOR IMMEDIATE RELEASE
October 14, 1988

ETHANE POLICY IMPLEMENTATION ANNOUNCED

Calgary . . . . Energy Minister Neil Webber and Minister of Economic Development and Trade, Larry Shaben, today announced the Government of Alberta's decision on the implementation of ethane policy.

The ethane policy, originally announced in August 1987, is intended to promote development of a functioning ethane market in Alberta. Ethane extraction and its use as a solvent in enhanced oil recovery and as a feedstock in the petrochemical industry has provided a major contribution to the economy of the province. This contribution can be further enhanced by a balanced policy that ensures a functioning ethane market that will allow further expansion of the world scale Alberta petrochemical industry, as, for example, is planned by Nova and Dow Chemical.

Dr. Webber explained that the ethane policy would ensure availability of a minimum supply of ethane from the straddle plant system while allowing the construction of new field plants to extract increased volumes of ethane and other natural gas liquids.

The precise level of the threshold volume will be determined by the ERCB as the level that will meet the demonstrated sustained operational needs of the debottlenecked existing ethylene plants for ethane from the straddle plant system. The level will also include the minimum volume of ethane required to move ethylene through the Cochin pipeline.

. . . / 2

"The most efficient approach to ethane extraction involves a balanced system including a viable straddle plant extraction system, extracting gas from the major gas pipelines leaving Alberta, in combination with a number of field ethane extraction facilities", Dr. Webber said. He added, "A minimum volume of ethane will be available to the straddle plants, maintaining the viability of straddle plant extraction as long as there is demand for straddle plant ethane for the petrochemical industry to upgrade within Alberta."

Mr. Shaben noted that Alberta's ethane supply is large enough to support enhanced oil recovery projects, the existing petrochemical plants as well as anticipated expansion. "Two companies are considering building ethylene plants in Alberta. We think that under this form of implementation, both could go ahead, "he said.

The threshold volume will be expressed on the basis of ethane at the inlet of the straddle plants. This will encourage upgrading of the straddle plants because increased recovery of ethane will not be at risk from additional upstreaming. This threshold volume policy will be in effect as long as contracts for ethane from the straddle plants meet or exceed the threshold level and removal of the threshold would reduce straddle plant efficiencies and cost structures.

Current projections, even after allowing for additional upstreaming, show that ethane volumes at straddle plants should remain well above threshold levels, explained Dr. Webber. Should the level be breached, however, the ERCB will order supply of ethane to make up the threshold volume from plants built since the policy was announced. Ethane price will be set by negotiation and, failing this, arbitration.

A separate royalty will be set for ethane. This ethane royalty will replace the current practice of considering ethane as natural gas for royalty purposes.

. . . / 3

The ERCB will approve applications for new field ethane extraction plants provided that conservation, social and environment requirements are met, that the plant is in the public interest and that plant operation would not result in the threshold volume level being breached. If these criteria are met, the ERCB may approve applications without a hearing.

The government issued a policy statement on ethane in August 1987 and the ERCB was asked to hold a hearing and provide recommendations on the policy implementation. The ERCB provided its recommendations in April 1988 and since then the government has held extensive discussions with the interested parties. In explaining the implementation decision, Dr. Webber indicated that the government has accepted the principles of the ERCB recommendations. He emphasized that the government recognizes the importance of the oil and gas industry and the petrochemical industry to Alberta. "The decision made concerning the implementation of the ethane policy will benefit both industries," he said, noting that "it provides opportunity for field development and encourages the expansion of, and investment in, the petrochemical industry."

- 30 -

For further information, please contact:

John Donner
Executive Assistant
Office of the Minister
Alberta Energy
(403) 427-3740

October 14, 1988

A STATEMENT ON IMPLEMENTATION OF AN ETHANE POLICY IN ALBERTA

On August 21, 1987 the Alberta Government issued a policy statement on ethane and the Energy Resources Conservation Board was asked to hold hearings and provide recommendations with respect to implementation of the policy.

The policy recognizes that the development of a world-scale ethane-based petrochemical industry in Alberta over the last ten years represents a major success in terms of the Government's objectives of economic diversification and maximum upgrading of Alberta's resources within the Province. This development reflects the industry's recognition of the stable and supportive business environment in Alberta and the long-term, secure, market-priced supply of the essential petrochemical feedstocks, especially ethane.

The Alberta Government also recognizes the important economic contribution of the oil and gas industry to Alberta and the investments it has made in support of a major objective of the Alberta Government, the encouragement of optimal resource development.

The Alberta Government believes that sufficient ethane is and will be available in the province to meet foreseeable demand for ethane for both petrochemical feedstock and enhanced oil recovery (EOR) solvent.

The Alberta Government is announcing measures which will maintain a functioning market in ethane wherein both the petroleum and petrochemical industries will have access to adequate and competitive sources of ethane supply and the incentive for further development of ethane-related activity in the province.

. . . / 2

The Alberta Government re-affirms its policy to ensure that ethane will be available for petrochemical use in Alberta. More specifically, the Energy Resources Conservation Board will include in further approvals of upstream ethane extraction facilities a condition that the upstream plants will be required to reinject or supply sufficient ethane to maintain the threshold volumes.

The Board provided its recommendations to the Government in April of this year. Since then extensive consultations have been held with all interested parties. After careful consideration of the ERCB report and the views of interested parties, the Government of Alberta accepts the recommendations of the ERCB in principle and will implement its ethane policy in the following manner:

Approval of Field Ethane Extraction Plants

The Energy Resources Conservation Board will approve applications for new field ethane extraction plants provided that it is satisfied that:

- Conservation, social and environment requirements are met;
- The plant is in the public interest;
- Operation of the plant would not result in the threshold volume level being breached.

Where these criteria are met the Board may approve applications without a hearing.

The rights of all parties directly affected by an application to have their concerns heard by the Board will remain as set out under current legislation.

. . . / 3

Threshold Volume

The ERCB has demonstrated that there is a large supply of ethane available in Alberta.

Therefore, recognizing:

- the integral part that ethane from straddle plants plays in the Alberta ethylene industry,

- the need for a balance in ethane extraction between field and straddle plants, and

- that a mix of field and straddle plants supplying ethane is an efficient approach to meeting needs for enhanced oil recovery and existing ethylene plant requirements, and providing feedstock for several new ethylene plants,

the ERCB will set a threshold volume at a level that will meet the demonstrated sustained operational needs of the existing ethylene plants, after the planned debottlenecking, for ethane from the straddle plants plus the minimum volume of ethane required for use as a buffer to move ethylene batches through the Cochin pipeline.

The threshold volume is to be expressed on the basis of ethane at the inlet of the straddle plants. This will encourage upgrading at the straddle plants because increased recovery of ethane due to efficiency improvements will not be at risk from additional upstreaming. Should the ethane content of the gas stream at the inlet deteriorate to the point that the ethane recoverable from the threshold inlet volume level, at current levels of straddle plant efficiency, would not meet the needs outlined above, the Energy Resources Conservation Board will review and adjust the threshold level to ensure those requirements can be met.

. . . / 4

The objective of the threshold volume policy is to ensure a viable straddle plant system for as long as it is needed to provide ethane for upgrading to ethylene within Alberta. Therefore, the threshold volume policy will remain in effect at the level outlined above as long as contractual commitments for ethane from the straddle plants to ethylene plants meet or exceed the threshold volume level and removal of the threshold would reduce straddle plant efficiencies and cost structures.

The ownership of the ethane available at the straddle plants will be dependent on the contractual commitments between ethylene plants, the straddle plant owners and shippers or producers of the gas. The policy is also independent of any specific ethylene plant using ethane from the straddle plant system. Although the threshold volume is calculated on the basis of existing petrochemical use, upon expiry of existing contracts, straddle plant ethane will be available for any ethylene upgraders who may wish to contract for ethane from straddle plants. In this manner the policy accommodates market forces while ensuring a balance in ethane supply provided by field and straddle plants.

The Supplying of Ethane if the Threshold Volume is Breached

It is the policy intent, and ethane supply and demand forecasts suggest, that the threshold volume level will be met without requiring the supplying of ethane from field plants to the straddle plant system. In the event the threshold level is breached, new plants (plants other than those approved and operating or under construction as of August 21, 1987) will be required to supply ethane to meet threshold volume needs. Royalty ethane not committed to petrochemical upgrading will be utilized first to make up the shortfall.

The supply of ethane to the straddle plant system should be negotiated where feasible but will be ordered by the Board if negotiations for volumes to satisfy the threshold fail.

. . . / 5

The price of ethane, including royalty ethane, that may have to be supplied to maintain the threshold volume will be set by negotiation. Failing agreement on price, an arbitration process will be triggered. The terms of the arbitration process will be specified to ensure that the cost structure of ethane available from the straddle plants is not materially affected.

Establishment of an Ethane Royalty

Currently, ethane is considered to be natural gas for royalty purposes. The Government will establish a separate royalty for ethane, similar to the royalty structure for other natural gas liquids. The royalty right, as is the case for all hydrocarbons, will include the right to take all or part of the ethane in kind.

APPENDIX 3A LIST OF PERMANENTLY EXEMPT FACILITIES

The following field facilities are not subject to the Government of Alberta ethane policy and the requirement to reinject ethane in order to maintain the threshold volume, because they were approved before 21 August 1987, the date on which the ethane policy was announced. The exemption applies only to the ethane extraction capacity listed below which was determined from the appropriate applications as being the capacity on 21 August 1987.

OPERATOR	PLANT LOCATION	ERCB PLANT APPROVAL NUMBER[a]	APPROVED ETHANE RECOVERY[a,b] (m^3/d)	PURE ETHANE EQUIVALENT (capacity exempt from policy) (m^3/d)
Esso[d]	Bonnie Glen	4095B	1 119[c]	1 099
Chevron[e]	Brazeau River	4151B	490	322
Pembina[f]	Diamond Valley	4540A	200[c]	191
Canadian Hunter[g]	Elmworth	4454	3 092	1 741
Esso[h]	Elmworth	3922	2 829	1 810
Esso[i]	Judy Creek	4663	3 863[c]	3 621
Shell[j]	Jumping Pound	4583A	445[c]	431
Chevron[e]	Kaybob South	3920	2 686	1 808
Conoco[k]	Peco	4499	543	366
Shell[j]	Waterton	4098B	933[c]	911
Amoco[l]	Wembley	4501	1 395	885

a In effect at August 1987.
b Ethane-plus mix.
c Specification ethane (conversion to pure ethane is based on the original application material balance and may differ from the 94 per cent pure specification ethane stated in footnote 5).
d Esso Resources Canada (formerly Texaco Canada Resources).
e Chevron Canada Resources Limited.
f Pembina Resources Limited (formerly Western Decalta Petroleum (1977) Limited).
g Canadian Hunter Exploration Ltd.
h Esso Resources Canada Limited (formerly Sulpetro Limited).
i Esso Resources Canada Limited.
j Shell Canada Limited.
k Conoco Canada Limited (formerly Ocelot Industries Ltd.).
l Amoco Canada Petroleum Company Ltd. (formerly Dome Petroleum Limited).

APPENDIX 3B LIST OF TEMPORARILY EXEMPT FACILITIES

The following existing plants are temporarily exempt from the Government of Alberta ethane policy and the requirement to reinject ethane because they do not deliver their residue gas to the existing straddle plant system. These plants will become subject to the policy when they commence delivery of gas to the straddle plant system.

OPERATOR	PLANT LOCATION	ERCB PLANT APPROVAL NUMBER[a]	APPROVED ETHANE RECOVERY (m^3/d)	PURE ETHANE-EQUIVALENT (m^3/d)
Chevron[d]	Acheson	5720	571[b]	209
Esso[e]	Bonnie Glen	4094B	1 692[c]	1 631
Petro-Canada[f]	Brazeau River	5659	491[c]	475
Esso[e]	Pembina	5607	1 737[b]	764

a In effect at the time ethane recovery was approved.
b Ethane-plus mix.
c Specification ethane.
d Chevron Canada Resources Limited.
e Esso Resources Canada (formerly Texaco Canada Resources).
f Petro-Canada Inc.

APPENDIX 3C LIST OF PLANTS COMPRISING THE STRADDLE PLANT SYSTEM

The following straddle plants are located on a pipeline transporting marketable gas and deliver their recovered ethane to the Alberta Ethane Gathering System, and hence are included under this policy:

NAME	PLANT LOCATION	OPERATOR	BASE YEAR ACTUAL Specification Ethane Recovered (m^3)	Recovery Efficiency (%)
Amoco Empress I) Amoco Empress II)	Empress	Amoco[a]	1 440 109[b]	57.1[b]
Petro-Canada	Empress	Petro-Canada[c]	1 367 014	58.8
EGLJV	Empress	Wolcott[d]	260 122	74.2
ANG	Cochrane	ANG[e]	2 115 044[f]	80.9
Amoco/ATCOR	Ellerslie	Amoco[a]	604 231	76.5[g]
		TOTAL	5 786 520	

a Amoco Canada Petroleum Company Ltd. (formerly Dome Petroleum Limited).
b Plant throughput and recovered ethane volumes were corrected for certain months to account for reporting error.
c Petro-Canada Inc.
d D. M. Wolcott and Associates Ltd.
e Alberta Natural Gas Company Ltd
f Adjusted to reflect approved gas throughput.
g Actual recovery efficiency adjusted by Board to account for certain months having unusually low recovered ethane volumes which do not reflect plant capability.

APPENDIX 4 **DETAILED CALCULATION OF THRESHOLD VOLUME**
(in terms of cubic metres per day of pure ethane)

I Total Outlet Threshold Volume

AGE I & II	demonstrated sustained operational needs	14 750[a]
plus	Cochin pipeline minimum buffer requirement	500
	Subtotal	15 250
less	Field Plant Contribution to Project Threshold volume at outlet conditions	940
Total Outlet Threshold Volume		14 310

II Allocation of Total Outlet Threshold Volume to Individual Straddle Plants

Plant	Actual Specification Ethane Recovered in Base Year (m^3)	Portion of Ethane Recovered in Base Year[b] (%)	Portion of Outlet Threshold Volume (m^3/d)
Amoco Empress I) Amoco Empress II)	1 440 109	24.9	3 562
Petro-Canada Empress	1 367 014	23.6	3 380
Wolcott Empress	260 122	4.5	644
Empress Composite	3 067 245	53.0	7 586
ANG Cochrane	2 115 044	36.6	5 230
Amoco Ellerslie	604 231	10.4	1 494
Total	5 786 520	100.0	14 310

a Actual 1989 calendar year pure ethane consumption of AGE I and II converted to a stream day basis and rounded.
b Percentages have been rounded.

APPENDIX 4 (cont'd)

III Conversion of Individual Plant Outlet Volumes to Inlet Volumes

Plant	Portion of Outlet Threshold Volume (m^3/d)	Average Base Year Recovery Efficiency[c] (%)	Inlet Threshold Volume (m^3/d)
Amoco Empress I)			
Amoco Empress II)	3 562	57.1	6 238
Petro-Canada Empress	3 380	58.8	5 748
Wolcott Empress	644	74.2	868
Empress Composite	7 586	59.0	12 854
ANG Cochrane	5 230	80.9	6 465
Amoco Ellerslie	1 494	76.5	1 953
Total	14 310		21 272

Total Inlet Threshold Volume = 21 272 m^3/d

$$\text{Overall Recovery Efficiency} = \frac{14\ 310}{21\ 272} = 67.3\%$$

---

c By using the average recovery factor to the nearest decimal to calculate the inlet threshold volume, the Board does not intend to suggest that the straddle plant recovery curves, which it will subsequently prepare, can be read to this accuracy.

APPENDIX 5 EXAMPLE OF A THRESHOLD VOLUME ADJUSTMENT
(for illustrative purposes only)

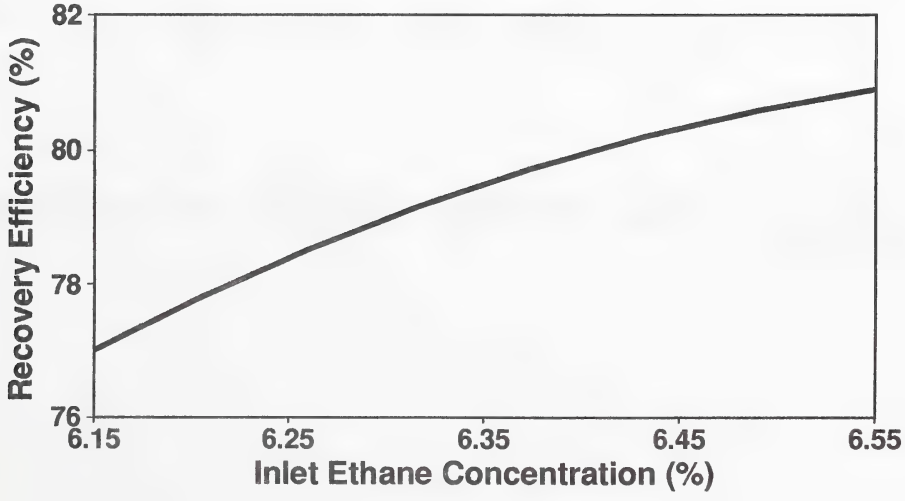
The procedure described here is an illustration of how an adjustment to the threshold volume, discussed in Section 5, might be made. The actual details of the calculation may differ, however, depending upon the circumstances at the time.

In this procedure one calculates the change in ethane concentration attributable to the amount of field plant ethane extraction occurring upstream of the straddle plant under consideration, at that straddle plant's gas throughput during the subject period. This ethane concentration is then added to the average measured ethane concentration in that same period. The resulting calculated ethane concentration corresponds to the ethane concentration that the straddle plant would have had in its inlet if there had been no upstream extraction of ethane occurring, in other words, if there had only been changes in ethane concentration due to causes other than upstreaming. Then, using the plant efficiency curves, the recovery efficiencies corresponding to the calculated and the measured ethane concentrations are determined. The difference between these two efficiencies is the change in efficiency due to upstream extraction of ethane. Because in this example the change in efficiency is a decrease and because it is significant, the resulting reduced recovery efficiency would be used to replace the base-year recovery efficiency in the threshold volume calculation shown in Appendix 4 in order to calculate a new threshold volume for the straddle plant and hence, a new total threshold volume on which to administer the policy.

Assumptions

1. In the base year at the Cochrane straddle plant, the total gas throughput was 10 894.9 x 10^6 m^3/d (29.85 x 10^6 m^3/d), average inlet ethane concentration was 6.55 per cent, and the recovery efficiency was 80.9 per cent.

2. The Cochrane recovery efficiency curve in the base year is as follows:



3. The total threshold volume is allocated to individual plants as determined in Appendix 4. Therefore for the Cochrane plant, the outlet threshold volume[a] would be 5230 m^3/d and the inlet threshold volume would be 6465 m^3/d at an 80.9 per cent recovery efficiency.

4. In 1994 during the first half of the year, the total gas throughput at the Cochrane straddle plant is 4525 x 10^6 m^3 (25.0 x 10^6 m^3/d) and the average ethane concentration at the

   inlet is measured as 6.25 per cent. This represents both the effects due to upstreaming as well as those caused naturally.

5. In 1994 the total amount of pure ethane-equivalent[a] being recovered at field plants located upstream of the Cochrane straddle plant is 200 m^3/d.

Adjustment Calculation

As a result of these changes, the threshold volume for the Cochrane plant would be subject to adjustment as follows:

- Average ethane content in the inlet stream with upstreaming

  = 6.25 per cent (the measured value)

- Ethane concentration corresponding to the amount of upstreaming that is occurring

  = [(recovered field plant liquid volume of pure ethane-equivalent)/(conversion factor from liquid m^3 to gaseous m^3/gas throughput] x 100 per cent

  = [(200 m^3/d/0.003 55 m^3/m^3/(25.0 x 10^6 m^3/d)] x 100

  = 0.22 per cent

- Therefore, the average ethane content in the inlet stream without upstreaming would have been = 6.25 + 0.22

  = 6.47 per cent

---

a Threshold volumes and ethane volumes are expressed in liquid volumes.

- Using the recovery efficiency curve for the Cochrane plant, one determines a recovery efficiency of 78.4 per cent for the plant with upstreaming (corresponding to the 6.25 per cent inlet ethane concentration) and a recovery efficiency of 80.5 per cent for the plant without upstreaming (corresponding to the 6.47 per cent inlet ethane concentration). In other words, the drop in recovery efficiency due to upstreaming = 80.5 - 78.4 = 2.1 per cent

- The reduction due to upstreaming would then be subtracted from the base-year recovery efficiency, 80.9 - 2.1 = 78.8 per cent, which is a redetermined recovery efficiency

- The new inlet threshold volume would be calculated by dividing the required outlet threshold volume by the redetermined recovery efficiency

  = 5230/0.788 = 6637 m^3/d

This compares to the 6465 m^3/d initially calculated in Appendix 4.

The new overall threshold volume would be 21 444 m^3/d

AC.1.IS

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter IL 90-10

TO: All Oil and Gas Operators 28 June 1990

REVISED PROCEDURES FOR CONTROL WELLS

1. INTRODUCTION

The Board, in consultation with CPA and IPAC, has decided to amend the Oil and Gas Conservation Regulations (Regulations) and revise procedures with regard to the administration of control wells in blocks and projects. The existing control well Regulations and policies, formulated under severe prorationing, were designed to protect correlative rights by preventing excessive lease-line drainage. Under production constraints imposed by the current Maximum Rate Limitation (MRL), and gas-oil ratio and off-target penalty factors, the Board finds that existing Regulations and policies are inconsistent with the fundamental intent of the control well.

The automatic assignment of control well status can result in production rates being imposed where there may be no equity concern, and rates can be needlessly restricted without consideration as to whether or not drainage is in fact occurring. In the future, the onus for identifying the need for imposition of control well status in order to prevent excessive lease-line drainage will be shifted to the operators. The Board further believes the current practice of diffusing a control well's off-target penalty over the entire block or project can create inequities contrary to the spirit of existing legislation on off-target wells.

2. REVISED POLICIES

The Board has therefore decided to amend the Regulations and restructure the procedures on control wells with a more flexible approach, while at the same time continuing to provide a means of protecting correlative rights. The Board will amend the Regulations at the earliest possible date. Effective 1 October 1990, the control well administrative procedures will be revised as follows.

2.1 Definition of Control Well

The Board believes that the present requirement that a control well be closer to the well causing control than the "least side dimension" of its drilling spacing unit (DSU) is no longer appropriate. With the onus now on the affected operator to show drainage, any arguments in this regard must of necessity consider the location of the control well within its DSU. Therefore, a control well will now be defined as "a well capable of producing oil which is within a block or project and which is completed in a drilling spacing unit contiguous to a drilling spacing unit containing a producing well outside the block or project".

2.2 Imposition of Control Well Status

Control well status will be imposed only in the following situations:

(a) Upon written request, where an operator can show evidence, to the satisfaction of the Board, that drainage is occurring.

(b) The control well is off-target, in which case, control well status will normally be applied upon written request by an affected party.

The off-target penalty factor will, in addition to the current practice of being applied against the block or project allowable, be applied directly against the control well itself. This will eliminate the current flexibility which permits transfer of the block or project allowable to an off-target control well.

2.3 Control Well Rates

(a) Projects - the control well will be assigned a rate equal to the greater of

- 20 m^3/d, or
- the product of the control well's DSU area and the per hectare base MRL prescribed for the pool type in the Board's MRL Order.

Thus, wells operating across a common lease line between competitively operated schemes of similar depletion type will receive the same control well rate. The Board may vary this formula to suit unique situations. The Board may also accept an alternative rate to that determined above provided such rate is mutually agreed upon by the parties concerned.

(b) Blocks - the control well rate will be equal to that assigned to other primary wells outside the block, as prescribed for that pool in the Board's MRL Order. As in the case of projects, this may be varied where the size of the contiguous DSUs are not the same.

3. TIMING

Effective 1 October 1990, the Board will remove control well status from all wells currently coded as such and, where a decision is made to retain control well status, will recalculate control well rates as prescribed above. The Board will, until 31 July 1990, accept written requests to retain existing control well status. These requests must provide technical arguments to substantiate claims of drainage.

Any questions with regard to this matter can be directed to the Board's Oil Department at 297-8566.

N. G. Berndtsson, P.Eng.
Manager
Oil Department